High Resolution Prediction of Gas Injection Process Performance for Heterogeneous Reservoirs

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Disclaimer

Abstract

This report outlines progress in the first quarter of the third year of the DOE project "High Resolution Prediction of Gas Injection Process Performance for Heterogeneous Reservoirs".

In this report we present an application of compositional streamline simulation in modeling enhanced condensate recovery via gas injection. These processes are inherently compositional and detailed compositional fluid descriptions must be use to represent the flow behavior accurately. Compositional streamline simulation results are compared to those of conventional finite-difference (FD) simulation for evaluation of gas injection schemes in condensate reservoirs.

We present and compare streamline and FD results for two-dimensional (2D) and three-dimensional (3D) examples, to show that the compositional streamline method is a way to obtain efficiently estimates of reasonable accuracy for condensate recovery by gas injection.

Contents

1. Executive Summary

A significant portion of current hydrocarbon reserves exists in gas condensate carrying formations. In analog to oil reservoirs, production of condensate fields by primary production only, will result in significant loss of the heavy ends due to liquid dropout below the dewpoint pressure. Gas cycling/injection schemes are often applied to enhanced condensate recovery by vaporization. Successful design and implementation of enhanced condensate recovery schemes require accurate prediction of the compositional effects that control the local displacement efficiency as well as a high-resolution representation of the geological formation carrying the hydrocarbons.

In this report we describe the results from using dispersion-free, semi-analytical one-dimensional calculations for enhanced condensate recovery by gas injection in compositional streamline simulation. We base our study on data from an existing condensate field and assess the quality of compositional streamline simulation through a sequence of increasingly complex geological models.

Initially, displacements in 2D vertical and areal models were investigated. The 2D calculation examples demonstrate that the effects of gravity can be neglected making the presented approach highly suitable for this type of displacement problems.

Second, a 3D-sector model containing 6 active wells was investigated. We demonstrate that significant speed-ups are available through the use of compositional streamline simulation relative to conventional finite difference simulations.

Finally, a single realization of the full-field geology was investigated. The full-field model involves 16 active wells.

All calculation examples were compared to conventional FD simulations and found in good agreement. The suggested approach provides a better control of numerical dispersion than does the equivalent FD simulations. Furthermore, Speed-ups between 2 and 3 orders of magnitude are available through the application of compositional streamline simulation for enhanced condensate recovery by gas injection.

2. Introduction

Gas cycling schemes for enhanced condensate recovery are inherently compositional because condensate is moved by transferring components to the mobile vapor phase. Hence, evaluation of the performance of such processes requires the use of compositional simulation. Recovery efficiency of a gas injection scheme is determined partly by the local displacement efficiency and partly by fluid flow within the reservoir. Local displacement efficiency is controlled by the phase behavior of mixtures of the injection gas with the fluids present in the reservoir, which is, in turn, strongly influenced by the fluid description used for equation-of-state calculations of phase behavior. Fluid flow is often controlled by reservoir heterogeneities. Therefore, accurate evaluation of the performance of a gas cycling scheme requires both high-resolution representation of heterogeneity in the reservoir and use of an adequate number of components to describe the phase behavior of the fluid.

FD compositional simulation is the conventional way to solve such problems. This approach involves solving a material balance written for each component, for each reservoir element (grid block), in each time step of the simulation, which requires at least one flash calculation per grid block per time step. For large models or complex fluid descriptions, this method can be sufficiently computationally expensive that field-scale calculations are impractically slow. In order to reduce computation time, current industry practice is to simplify the geological model and fluid description. As a result, there is clearly some loss of accuracy due to the less detailed representation of phase behavior and reservoir heterogeneities, as well as the effects of numerical errors due to large grid blocks.

An alternative to conventional FD compositional simulation is compositional simulation streamline[1,2.] In this approach, the flow is represented as a series of one-dimensional (1D) displacements along streamlines. For more details on streamline simulation see ref. 3.

In reservoir displacements that are controlled by heterogeneities, streamline locations change slowly, and hence streamlines can be updated infrequently. The resulting simulations run much faster than comparable FD simulations[1,2] if an efficient method is available for solving the 1D compositional flow problem.

In this paper, we consider the application of compositional streamline simulation to displacement of a gas condensate by CO_2. For the purposes of this comparison, we fix the streamlines at their initial locations. Hence, we ignore the effects of changing mobilities on streamline locations, and we also ignore the effects of gravity. Because the differences in viscosity between the injected CO_2 and the gas in place are modest, as are differences in density, the use of fixed streamlines is a reasonable approximation, but it is an approximation. Effects of volume change on mixing are considered in propagating the compositions along streamlines, but are not considered in the pressure solve. This simplification is justified since there is not an appreciable amount of oil present for significant dissolution of CO_2 into the oil phase. Moreover, CO_2 is very efficient at vaporizing the condensate, resulting in very small saturations behind the leading edge of the displacement front. When volume change is considered, recovery at a given time is slightly lower since the amount of CO_2 available for displacement is reduced by the amount of volume change that occurs when CO_2 dissolves in the condensate.

To examine the effectiveness of streamline simulation, we compare results of conventional FD simulation with streamline simulation results for a sequence of increasingly complex problems: (1) 1D displacement, (2) horizontal and vertical 2D displacements, (3) a 3D displacement in a section of a field, and (4) a full field-scale 3D displacement. In the sections that follow we examine the advantages and limitations of streamline simulation for condensate recovery processes.

3. Reservoir Fluid Description

In all the displacements considered here, the system is initialized at 120 bar and 375 K (below the dew point pressure); immobile condensate is present everywhere in the reservoir. A description of the fluid is listed in Table 1. To provide an accurate description of retrograde behavior, the reservoir fluid is represented by a 13 component description; generated by the procedure of Pedersen *et al*.[4] Table 2 reports the properties of the characterized fluid. The equation of state model was tuned to match the results of a constant volume depletion (CVD) experiment. Fig. 1 compares the predicted liquid drop out with the CVD experiment.

4. Simulation Comparisons

The following calculations were performed to investigate the performance of compositional streamline simulation:

1. 1D model. An analytical solution was obtained by method of characteristics[5-8]. This approach can be used when the initial composition is everywhere uniform and the injection gas composition does not change with time.

2. 2D model. A 2D model was constructed, consisting of an injector and producer at either end of the system. Table 3 summarizes model parameters. The permeability field was constructed using sequential Gaussian simulation[9], tied to logs from a injector and producer pair of the full field reservoir model.

3. 3D model. A 3D model, based on a sector of the field model was constructed. Table 4 summarizes model parameters. The permeability field was simulated using sequential Gaussian simulation, again tied to well log data from the full field model.

4. Full field model. Comparison of streamline simulation and finite difference methods were applied to assess a gas injection scheme for enhanced condensate recovery on a currently producing reservoir. Model parameters are summarized in Table 5. The geological reservoir description was provided by the operator.

In this study, Eclipse 300 (compositional FD simulator) and a streamline simulator written by Batycky[10] and modified by Jessen and Orr[2] were used.

4.1 1D Displacement

The analytical solution for displacement of the initial mixture by pure CO_2 is shown in Fig 2. The technique for constructing the analytical solution is described in detail by Ermakov[7] and Jessen[8]. The displacement of condensate differs slightly from those solved previously. When the initial composition is inside the two-phase region, as it is here, the key tie lines that determine solution behavior are unchanged, but some of the segments that are present when the initial composition is in the single-phase region may be missing. Fig. 2 shows that as CO_2 propagates through the reservoir, condensate is recovered through a series of vaporizing shocks, with light components displaced more rapidly than heavy components. The analytical solution shows that a bank of condensate (segment of low gas saturation) propagates near the leading edge of the displacement. This occurs because components vaporized by the injected CO_2 transfer into the condensate phase as they propagate downstream.

Finite difference slimtube simulations were performed with 100, 500, 1000 and 5000 gridblocks. Fig. 2 compares the analytical and FD solutions. In the coarse-grid FD simulations, much of the compositional detail of the displacement is obscured by numerical dispersion. The bank of condensate the leading edge of the displacement is not captured for grid resolutions coarser than 1000 gridblocks. The total mobility distribution, shown in the middle panel of Fig. 2, is also poorly resolved in the coarse-grid FD simulations, which will influence flow patterns in 2D and 3D displacements. In many larger scale simulations, far fewer grid blocks are used between wells. Thus, the effects of numerical dispersion can be expected to influence predictions of displacement performance in multidimensional FD simulations, just as they do in the 1D simulations.

The sensitivity of a displacement to the effects of numerical dispersion depends on the phase behavior of the system. That sensitivity can be assessed by the method of Jessen, *et al*.[11] The system considered here is highly sensitive to dispersion (with a dispersive distance of 0.26). If physical dispersion is incorporated into the flow problem, the saturation profile will resemble profiles of the FD simulations; features such as shocks and the condensate bank at the leading edge of the displacement are not as well defined. Even so, in coarse gridblock FD simulations, the magnitude of numerical dispersion easily exceeds what is physically realistic.

4.2 2D Displacements

To investigate the magnitude of gravitational effects, FD simulations were performed for the same permeability distribution (Fig. 3) oriented vertically (xz) and horizontally (xy). For gas cycling in this condensate system, heterogeneity dominates flow, and ultimately controls recovery. Comparison of the gas saturation in the formation after 2000 days of injection, shown in Fig. 4 illustrates the modest effect of gravity. At reservoir conditions, CO_2 is has a higher density thane the mobile vapor phase (ρ_{CO2} = 250.04 kg/m^3, ρ_{gas} = 183.64 kg/m^3). Fig. 4a shows the distribution of gas saturation obtained by FD simulation for horizontal orientation of the 2D porous medium. Figs. 4b and 4c show similar results for vertical orientations. The injection rate for the simulation shown in Fig. 4c is half that of Fig. 4b. At the lower rate, some evidence of segregation of the heavier CO_2 can be seen at the lower edge of the cross section. Fig. 5 shows, however, that these differences have almost no effect on recovery. Through out this paper we refer to recovery as defined by the ratio of produced liquid at standard conditions to that of the initial fluid in place also taken at standard conditions.

The corresponding plot of the gas saturation for the 2D streamline simulation is shown in Fig 4d. Because effects of gravity are neglected in the streamline simulation, there is no difference between the vertical and horizontal simulations for the streamline approach. The produced gas-oil ratios (GOR) for all 2D simulations are compared in Fig. 6.

These results are consistent with the gravity numbers for these displacements: Zhou *et al.*[12] discuss the scaling of multiphase flow in heterogeneous porous media and use gravity numbers (N_{gv}) defined by

$$N_{gv} = \frac{\Delta\rho \cdot g \cdot L \cdot K_{ave}}{H \cdot v \cdot \mu}, \tag{1}$$

where $\Delta\rho$ is the density difference between the fluid in place and the injected fluid, g is the gravity, L is the length of the system, K_{ave} is the average permeability in, H is the height of the system, v the flow velocity and μ the viscosity of the fluid in place. Zhou *et al.*[12] classify the flow to be dominated by gravity forces if

$$\frac{N_{gv} M}{M+1} >> 1, \tag{2}$$

where M is the endpoint mobility ratio. Based on the properties of fluids and formation given in Table 6, N_{gv} is evaluated to ≈ 13.2, M = 0.84 and hence, the left-hand side of Eq. 2 equals 6.0.Thus, these displacements lie in the transition region between viscous-dominated and gravity dominated flows. The saturation maps shown in Fig. 4a-c confirms that there is some impact of gravity, but its overall effect on displacement performance is small.

The streamline method predicts condensate recovery that agrees well with the FD simulation results. Just after breakthrough, the SL recovery is slightly better because of the accurately represents the condensate bank near the leading edge of the displacement. At later times, preferential flow of CO_2 through high permeability paths, which can be seen in Fig. 4d, reduces the rate of recovery in the SL simulations. As a result, condensate in the lower permeability regions is not swept as efficiently as in the high permeability paths. Numerical dispersion in the FD simulation smears the front of the condensate bank, reducing gas mobility in the high permeability paths, and increasing the sweep efficiency in low permeability regions at later times.

Numerical effects are also observed when GORs are compared for streamline and FD methods (see Fig. 6). Earlier breakthrough occurs along the high mobility streamlines, which is reflected by an earlier rise in the GOR once breakthrough occurs. Once gas flow is established through the high permeability flow paths, surrounding low permeability zones are swept more slowly in the streamline simulations. Despite the differences between the FD and SL simulations, however, the overall agreement between the recovery and GOR predictions is actually quite good for this problem in which gravity effects and mobility contrasts are modest. We argue, therefore, that gas displacement problems like the ones considered here are good candidates for compositional streamline simulation.

4.3 3D Displacement

Fig. 7 shows the permeability distribution and the well locations of the 3D-sector model. The sector model represents a $300*900*50m^3$ block of the full field where gas is produced from 5 wells, while CO_2 is injected in a single well. Streamline- and FD-simulations were run for 2500 days of injection, equivalent to 2 pore volumes of CO_2 injected (PVI). Saturation distributions at 2 PVI, predicted by streamline simulation and FD simulation are reported in Figs. 8 and 9.

Comparing Figs. 8 and 9 clearly demonstrates that the FD simulation of this gas injection process is strongly affected by numerical dispersion. In the FD simulation (Fig. 9), the leading edge of the displacement is smeared out significantly, covering almost the entire bottom layer of the sector model. At an early time in the displacement, the injected gas reaches the producers p_2

and p_3. At this point, further invasion of the domain slows down in the streamline simulation, due to the establishment of the channels. Consequently, some of the regions in the bottom face of the formation are still upswept after 2500 days of injection.

An alternative representation of the simulation results is given in Fig. 10. The figure shows each layer of the formation at 2500 days of injection for both the FD and the SL simulation. Comparing the columns in Fig. 10 clearly confirms the scaling argument from the 2D displacements; that viscous forces/heterogeneity dominated the flow. A second observation is the cloudy look of the saturation distribution in the FD simulation; a manifest of numerical dispersion. As the front smears out it slows down the directional flow in high permeable zones and enhances the areal sweep.

The corresponding recovery and GOR curves for the sector model are shown in Fig. 11. Breakthrough occurs slightly earlier when the displacement is simulated using streamlines. Again, this is related to formation of high flow zones once the displacement front reaches a producer. CO_2 bypasses condensate in the upswept areas resulting in a lower recovery, but high local displacement efficiency in the swept zones. For the FD simulation the picture is opposite; Due to dispersion a larger area gets in contact with the injected CO_2 while the local displacement efficiency in parts of the swept zones is fairly low. The trade off between sweep efficiency and local displacement efficiency results, for this case, in a higher recovery prediction by the FD simulation, which may very well be optimistic.

5 Full Field Displacement

5.1 Reservoir Description

The reservoir description used in this example is typical of carbonate reservoirs found in the Western Canadian Sedimentary Basin. Average reservoir properties are summarized in Table 7. This field is a highly dolomitised reefal complex, located at a depth of approximately 3500 m. The reservoir has a northwest strike and southwest dip of approximately 25 m/km. Gas is stratigraphically strapped updip, containing 56 BCM of gas initially in place. It is estimated that 6 MMm^3 of condensate will be left in the reservoir at the time of abandonment.

This field is a large continuous feature, covering over 50 sections of land, penetrated by only 16 wells (Fig. 12). Well spacing is typically 1 to 2 sections. Permeability distribution and well locations for this simulation example are given in Fig.13. Given the heterogeneity resulting from the primary depositional environment and subsequent diagenetic effects, large uncertainty exists in the descriptions of the reservoir heterogeneities. Hence, the permeability field generated in this study is one of many possible scenarios.

In this development scenario, 100% CO_2 injection into three injector wells (8-01N, 3-10, 8-01S) was modeled. Production occurs from the remaining 13 wells. Injection volumes were based on production rates from surrounding wells.

5.2 Displacement Simulation

CO_2 was injected for approximately 49 years (1.16 PVI) at fixed rates of 15500, 3000 and 14000 reservoir m^3/day. Saturation distributions in the reservoir at the end of injection are given for the FD simulation and the streamline simulation in Figs. 14 and 15. Excellent agreement is observed between the flow allocations predicted by the two simulation methods. As for the sector model, the displacement front of the FD simulation is more diffuse than that of the streamline calculation. Recovery predictions and GORs are given in Fig. 16. Prior to breakthrough the FD and streamline methods are in almost perfect agreement. Arguments similar those of the sector model simulation apply for the full-field displacement calculation. The tradeoff between sweep and local efficiency result in a slightly higher recover prediction and later breakthrough time for the FD approach. For both methods, however, the ultimate recovery after 49 years of injection is low due to the large upswept areas, suggesting that a better injection-well placement/configuration would be advisable.

6. Speed Up Factors

Table 8 summarizes computational times for the various stages of this study. Speed-up factors depend quite strongly on system size[1]. For the systems investigated, speed-up factors of two to three orders of magnitude were observed. For the FD simulations, computational requirements scale roughly as the third power of the number of gridblocks[1]. Streamline simulations scale roughly linearly with model size. Hence, speed-ups will grow rapidly with model size.

In the 3D displacement case, the FD simulation took over three orders of magnitude longer to run than the streamline simulation. This model is only a small section of the real reservoir (1.4%). If this detail of resolution were extrapolated to a field scale simulation, a FD simulation would be prohibitively long. In this situation, streamline simulation would be the only reasonable tool.

In the full field displacement case, the speed up factor is not as dramatic. This is due to the relatively low number of active gridblocks. Even at this relatively coarse resolution, the speedup factor is two orders of magnitude, and given the adverse effects of numerical dispersion, the streamline simulation results are likely to be closer to physical reality than the FD results.

With the advent of more powerful processors, million cell geological models are commonly constructed. To capture the effects of this level of detail, streamline simulation is the only method currently fast enough to simulate recovery processes in these systems. If needed, the number of components used in the fluid description can also be increased, allowing better characterization of PVT behavior. Reduced computational times afforded by streamline simulation make this a useful tool for risk analysis. Equiprobable geological realizations can be tested, producing a more robust assessment of risk and uncertainty.

7. Discussion

This simulation study has demonstrated that compositional streamline simulation is a reasonable alternative to FD simulation for modeling gas injection processes in some condensate reservoirs, particularly when the flow problem is dominated by heterogeneity as in the presented case. By fixing the streamlines in time, we do not account for crossflow; i.e. flow not aligned with the streamlines. However, for gas condensates with immobile liquid saturations, gravity will play a minor role due to the low density contrast as will viscous cross flow due to the low mobility contrast.

The approach described here also is limited by the assumptions of constant initial and injection composition. If those conditions are not satisfied, a numerical method is required for solving the 1D flow problem[1,13,14]. Variable compositions along streamlines would also arise after streamline updating.

Gravity segregation has successfully been implemented and tested for immiscible streamline simulators[15,16]. However, for compositional simulation operator splitting has not yet been applied for gravity driven flows. Additional research will be required to reduce mass balance errors that arise in streamline simulation when streamlines are updated, or due to changing well conditions or gravity.

8. Conclusion

1. Compositional streamline simulation is a fast and effective tool for simulating gas injection schemes in a condensate reservoir. For the systems investigated, speed up factors of two to three orders of magnitude were observed, allowing fast assessment of process performance that is at least as accurate as predictions by conventional finite difference simulation.

2. Recovery efficiency is a complex balance of sweep efficiency and local displacement efficiency effects. For the condensate system investigated, numerical dispersion associated with compositional FD simulation resulted in optimistic recovery predictions. Compositional streamline simulation reduced these effects, by more accurately modeling of the compositional displacement processes and fluid flow patterns in the subsurface, thus producing more realistic predictions of fluid distribution in the reservoir.

3. Condensate recovery by dry gas injection of CO_2 occurs through a series of vaporizing shocks; efficiently recovering dropped out condensate in areas where the injection fluid contacts the reservoir. Enhanced recovery in condensate reservoirs by gas injection is dominated by heterogeneity.

4. Additional research on compositional streamline simulation methods is needed to handle efficiently the effects of gravity, capillary pressure, streamline updating and nonuniform initial conditions.

9. References

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Nomenclature:

g	: gravity
H	: thickness of formation
K_{av}	: average permeability in vertical direction
L	: length of formation
M	: Mobility ratio
N_{gv}	: gravity to viscous number
ρ	: mass density
μ	: viscosity

Table 1. Fluid composition.

Component	Mol fraction
CO_2	0.0670
H_2S	0.3536
N_2	0.0169
C_1	0.3595
C_2	0.0790
C_3	0.0337
iC_4	0.0097
nC_4	0.0200
iC_5	0.0068
nC_5	0.0101
C_6	0.0115
C_{7+}	0.0332

Mw_{C7+} = 113 g/mole, ρ_{C7+} = 0.9 g/cm^3

Table 2. Characterized fluid.

Pseudo-component	Mol fraction	MW (g/mol)	T_c (°K)	P_c (bar)	z_{crit}	Acentric factor
N2	0.0171	28.016	126.2	33.60	0.2895	0.040
CO2	0.0576	44.010	304.2	72.90	0.2744	0.228
H2S	0.3562	34.076	373.5	88.50	0.2857	0.080
C1	0.3631	16.043	190.6	45.40	0.2737	0.008
C2	0.0798	30.069	304.5	48.20	0.2850	0.980
C3	0.0340	44.096	369.8	41.90	0.2803	0.152
C4	0.0300	58.123	419.6	37.01	0.2737	0.188
C5	0.0171	72.150	465.9	33.34	02627	0.2413
C6	0.0116	86.177	507.4	29.30	0.2656	0.2960
C7	0.0117	94.000	573.9	41.46	0.2631	0.2651
C8	0.0126	113.52	648.2	32.53	0.2594	0.3437
C10	0.0053	141.52	630.0	30.17	0.2463	0.4489
C12	0.0039	190.00	683.2	26.92	0.2373	0.6305

Table 3. Model parameters for 2D Displacement.

Nx	200
Ny	1
Nz	25
dx (m)	10
dy (m)	10
dz (m)	2
number of wells	2 (1 injector, 1 producer)

Table 4. Model parameters for 3D displacement.

Nx	30
Ny	90
Nz	5
dx (m)	10
dy (m)	10
dz (m)	10
number of wells	6 (1 injector, 5 producer)
nugget effect	0.20

Table 5. Full field displacement.

number of active blocks	5774
dx (m)	300
dy (m)	300
dz (m)	10
number of wells	16 (3 injectors, 13 producers)

Table 6. Properties used in scaling analysis (N_{gv})

Viscosity of CO_2	0.025 cp
Viscosity of mobile gas phase	0.021 cp
Density difference ($\Delta\rho$)	66.4 Kg/m^3
Formation thickness	50m
Formation length	2000m
Flow velocity	0.5 m/day
Average permeability	125 mD

Table 7. Average reservoir properties for full field model.

Initial reservoir pressure (MPa)	36.5
Dewpoint pressure (MPa)	16.5
Reservoir temperature (K)	375
Formation thickness (m)	25
Porosity (%)	10
Water saturation (%)	10
Permeability (mD)	125

Table 8. Speed up factors for displacement cases (1.6MHz).

displacement	Number of active gridblocks	FD (s)	Streamline (s)	Speed up factor
2D	5000	7406	14	499
3D	13500	38991	24	1624
Full field	5774	4446	19	234

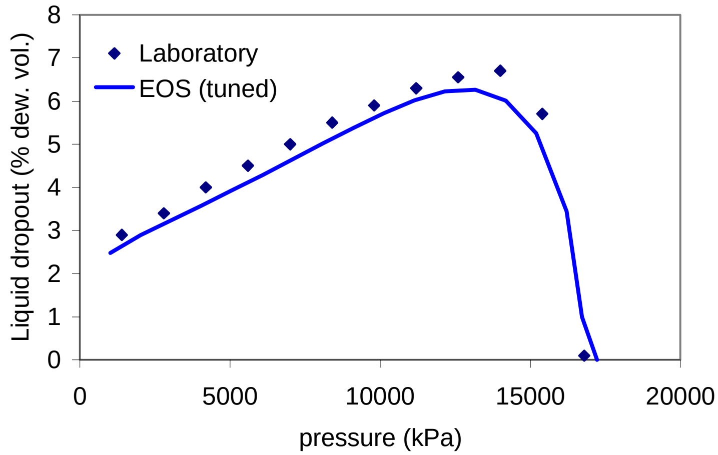

Fig. 1: Comparison of EOS predictions with laboratory data.

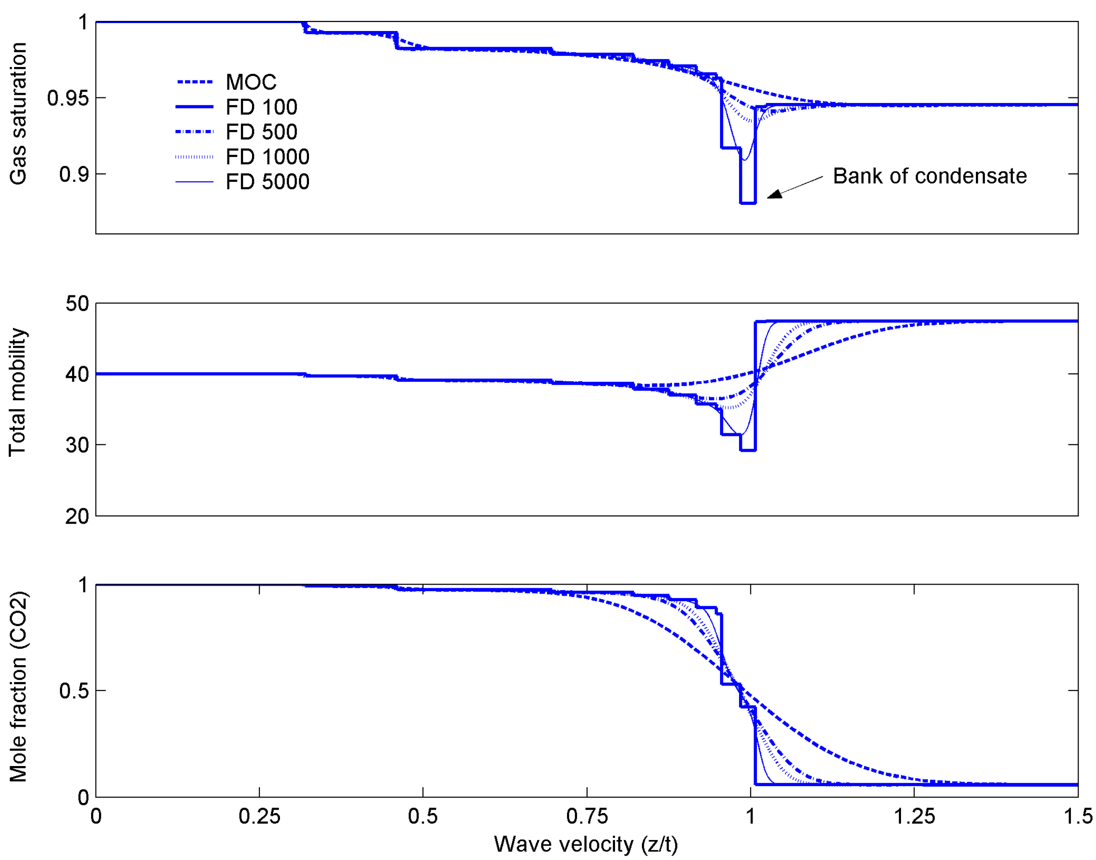

Fig. 2: Semi-analytical (MOC) and numerical (FD) profiles for the 1D gas injection problem.

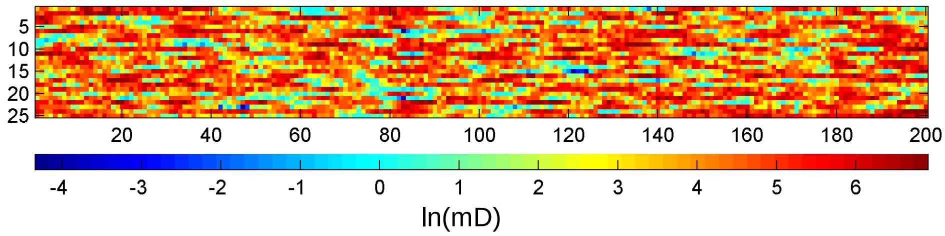

Fig 3: 2D displacement permeability field. Average permeability 125 mD.

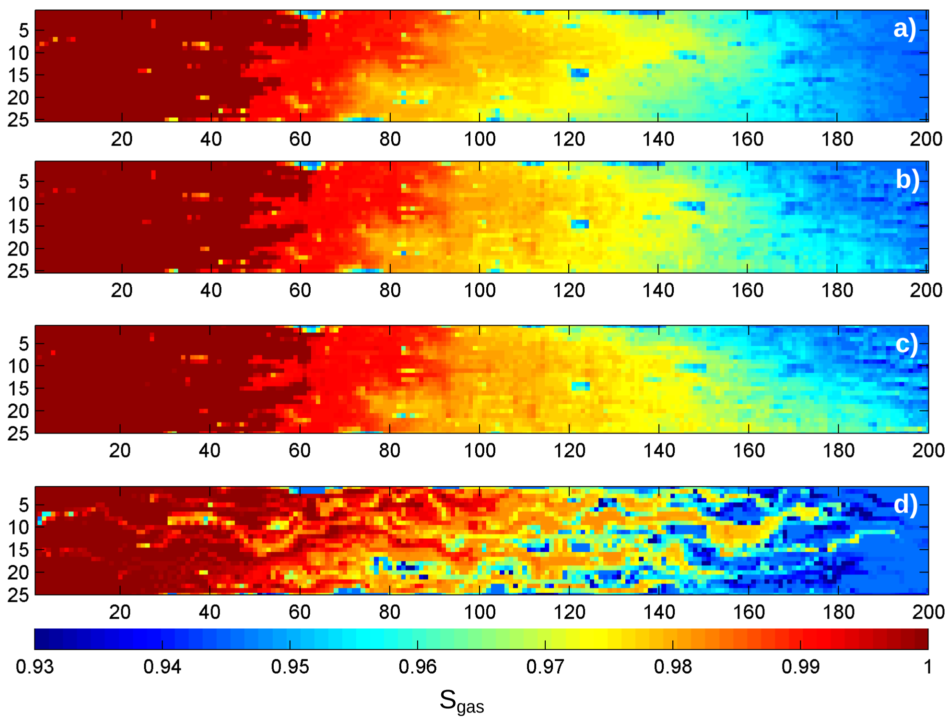

Fig.4: Gas saturation after 2000 days of high-rate injection: a) FD simulation of xy oriented permeability, b) FD simulation of xz oriented permeability, c) FD simulation of xz oriented permeability at low rate (4000 days) and d) SL simulation of xy (or xz) oriented permeability.

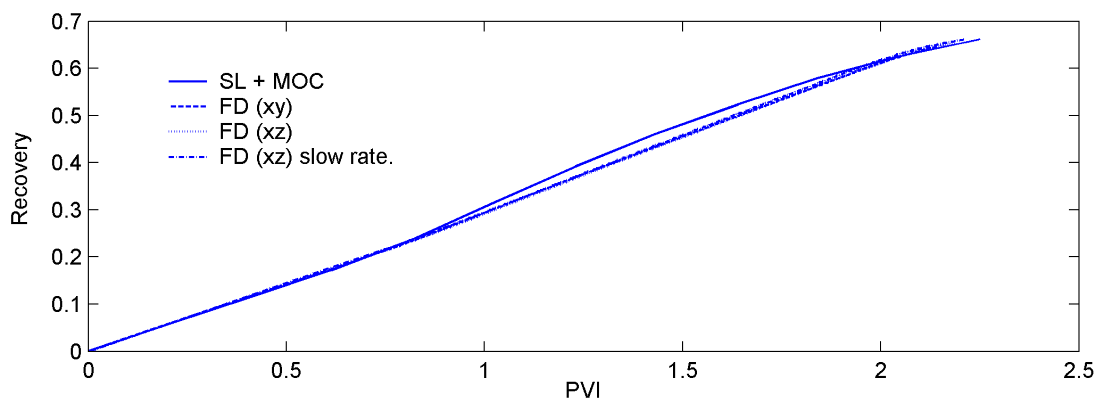

Fig. 5: Recovery predictions by: Streamline simulation (SL), areal (xy) FD simulation, vertical (xz) FD simulation and vertical FD simulation at low injection rate.

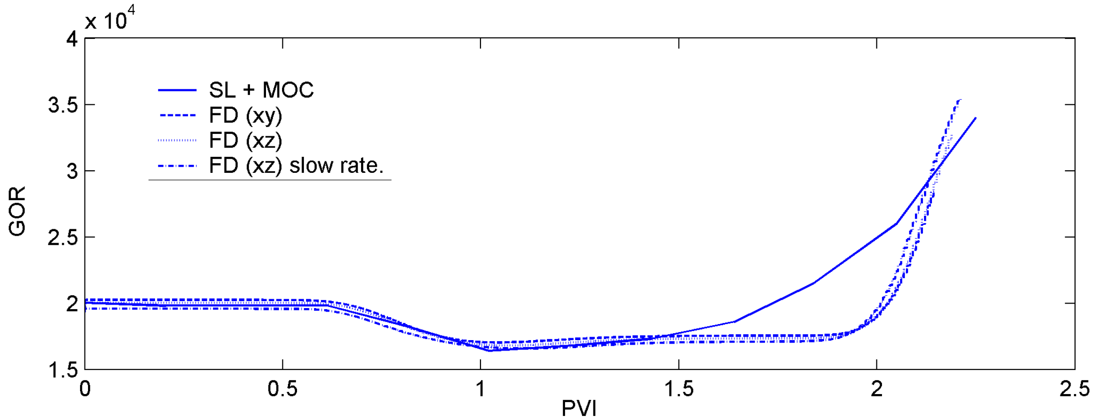

Fig. 6: Predictions of gas-oil ratio (GOR) by: Streamline simulation (SL), areal (xy) FD simulation, vertical (xz) FD simulation and vertical FD simulation at low injection rate.

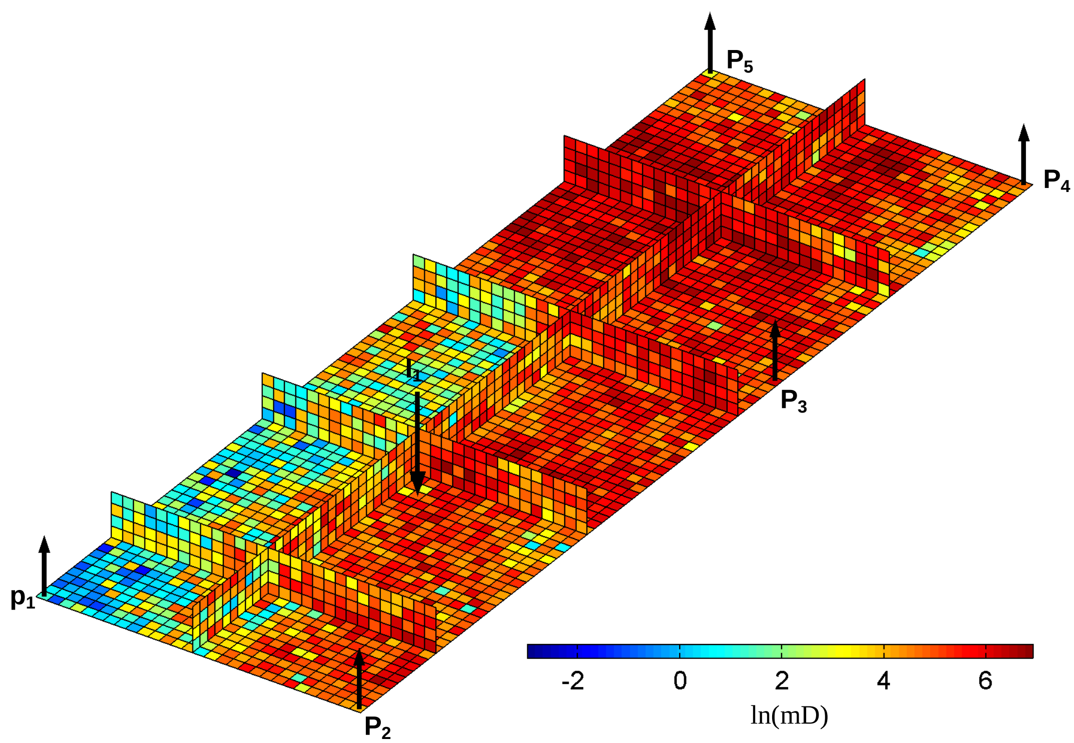

Fig. 7: Permeability field and well locations of the sector model (1 injector and 5 producers).

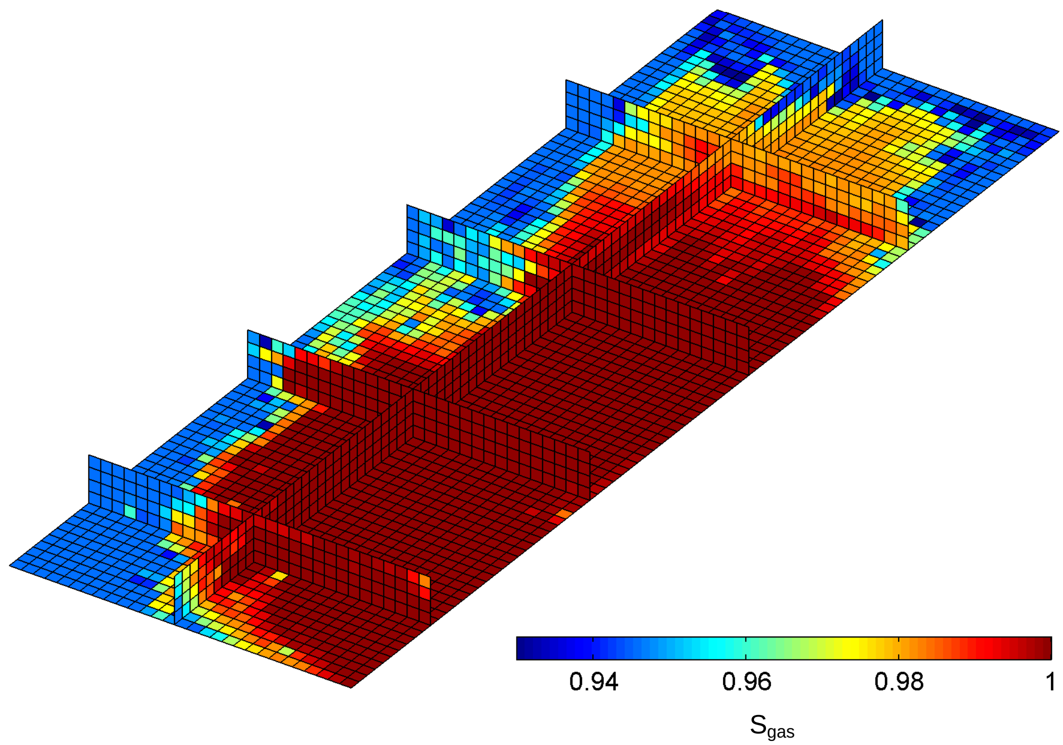

Fig. 8: Saturation distribution after 2500 days of injection predicted by SL simulation.

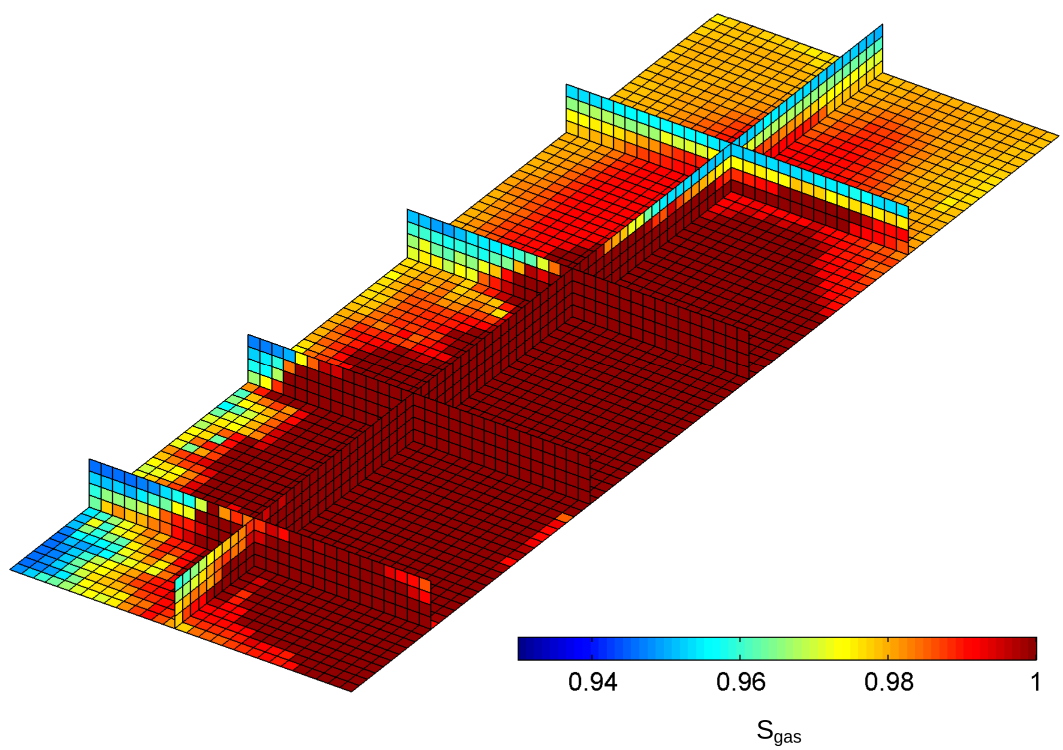

Fig. 9: Saturation distribution after 2500 days of injection predicted by FD simulation.

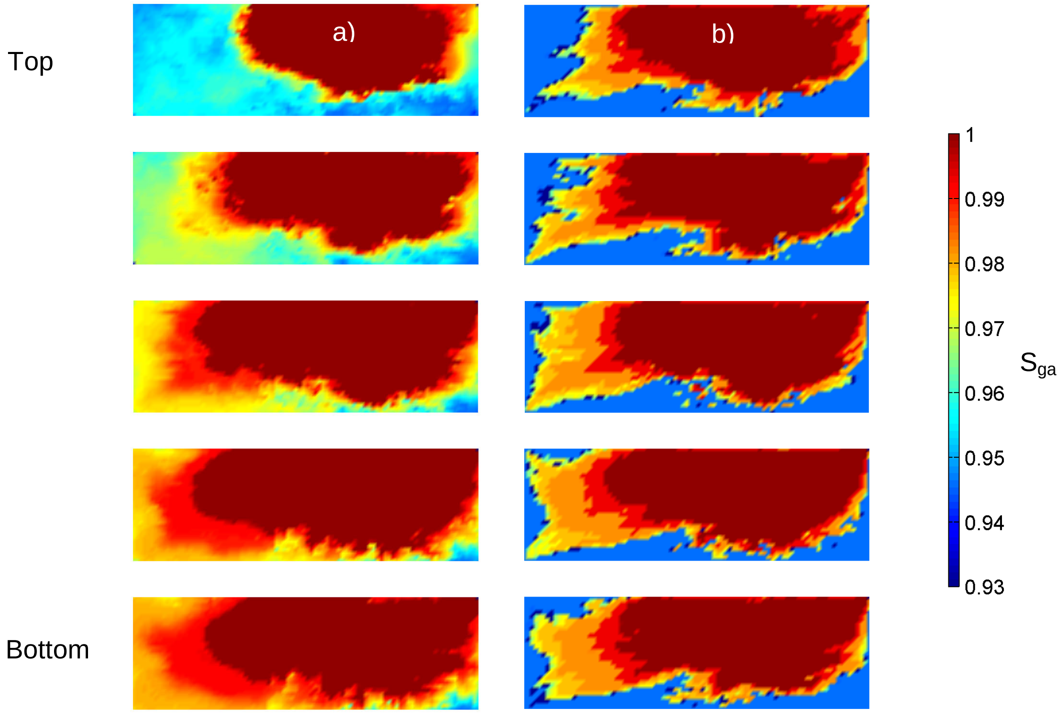

Fig. 10: Saturation distributions in areal cross-sections of the sector model after 2500 days of injection predicted by: a) FD simulation and b) Streamline simulation

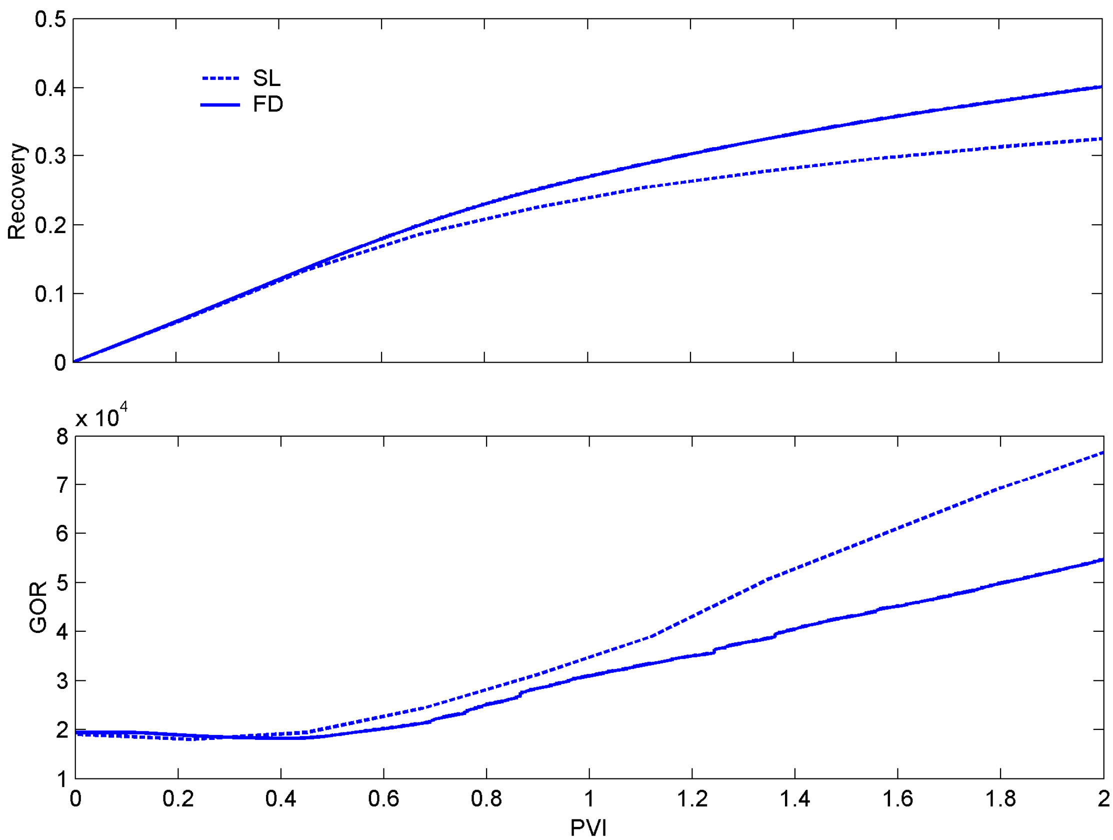

Fig. 11: Recovery and GOR predictions from SL simulation and FD simulation of sector model.

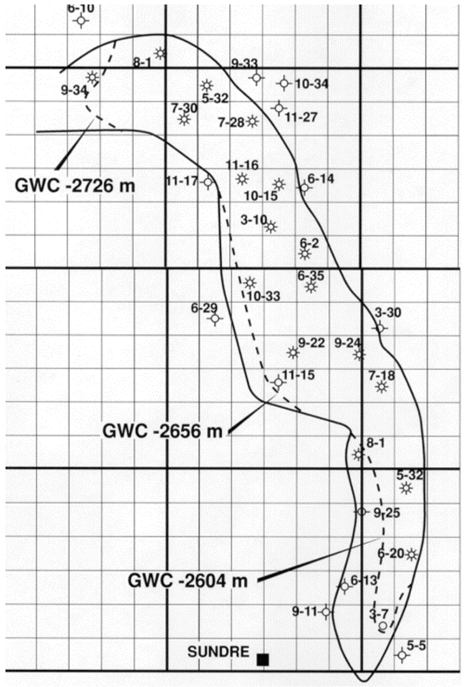

Fig. 12: Map of reservoir used in the full-field simulation.

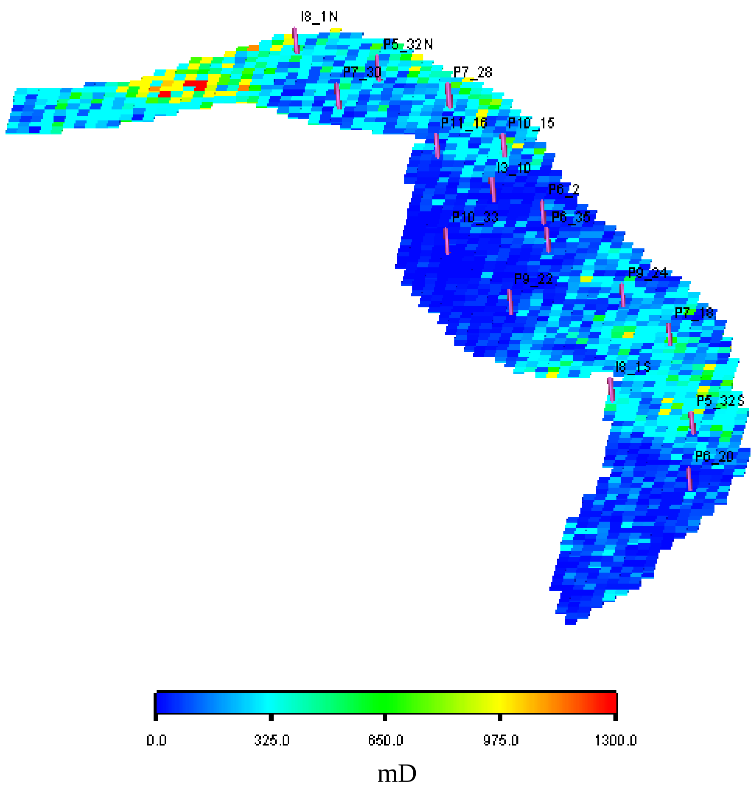

Fig. 13: Permeability map of full-field model.

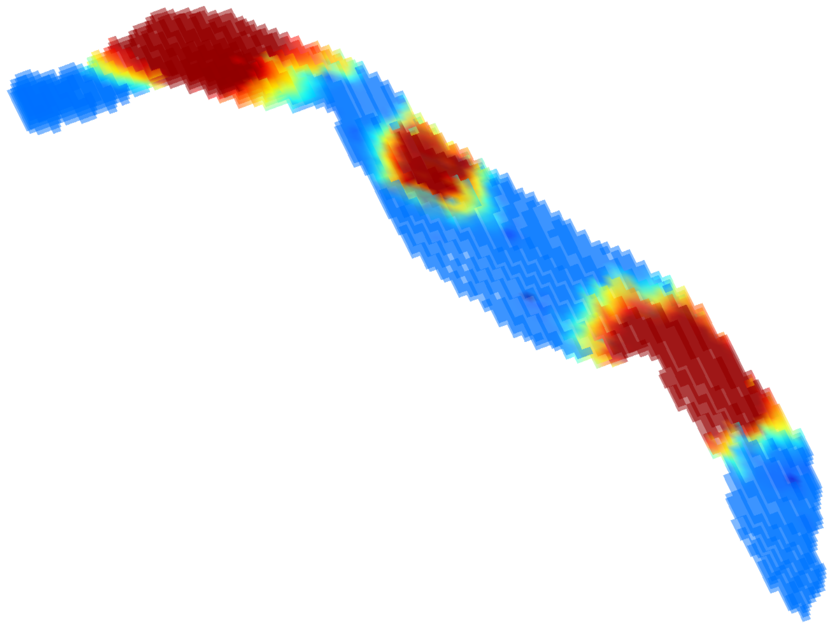

Fig. 14: Top view of gas saturation after 18000 days of injection (1.16 PVI) predicted by FD simulation.

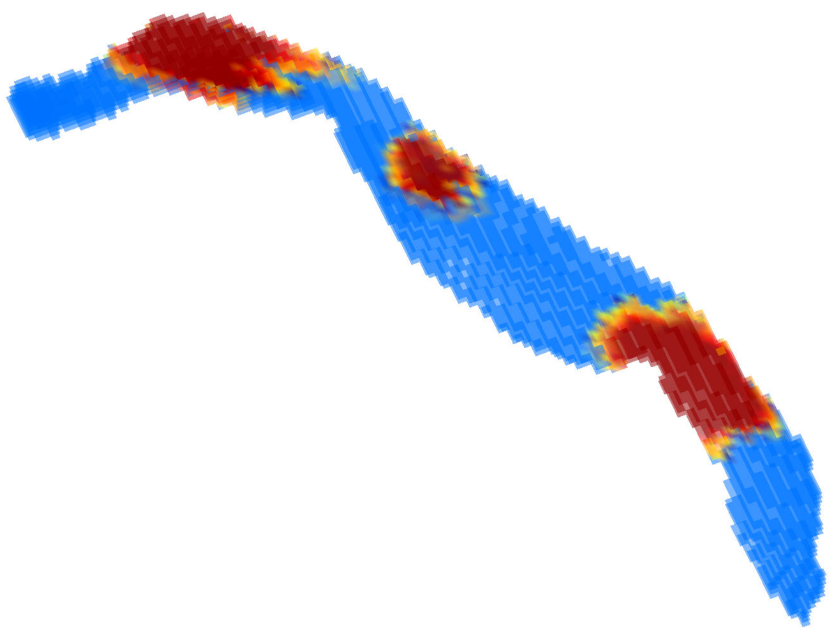

Fig. 15: Top view of gas saturation after 18000 days of injection (1.16 PVI) predicted by SL simulation.

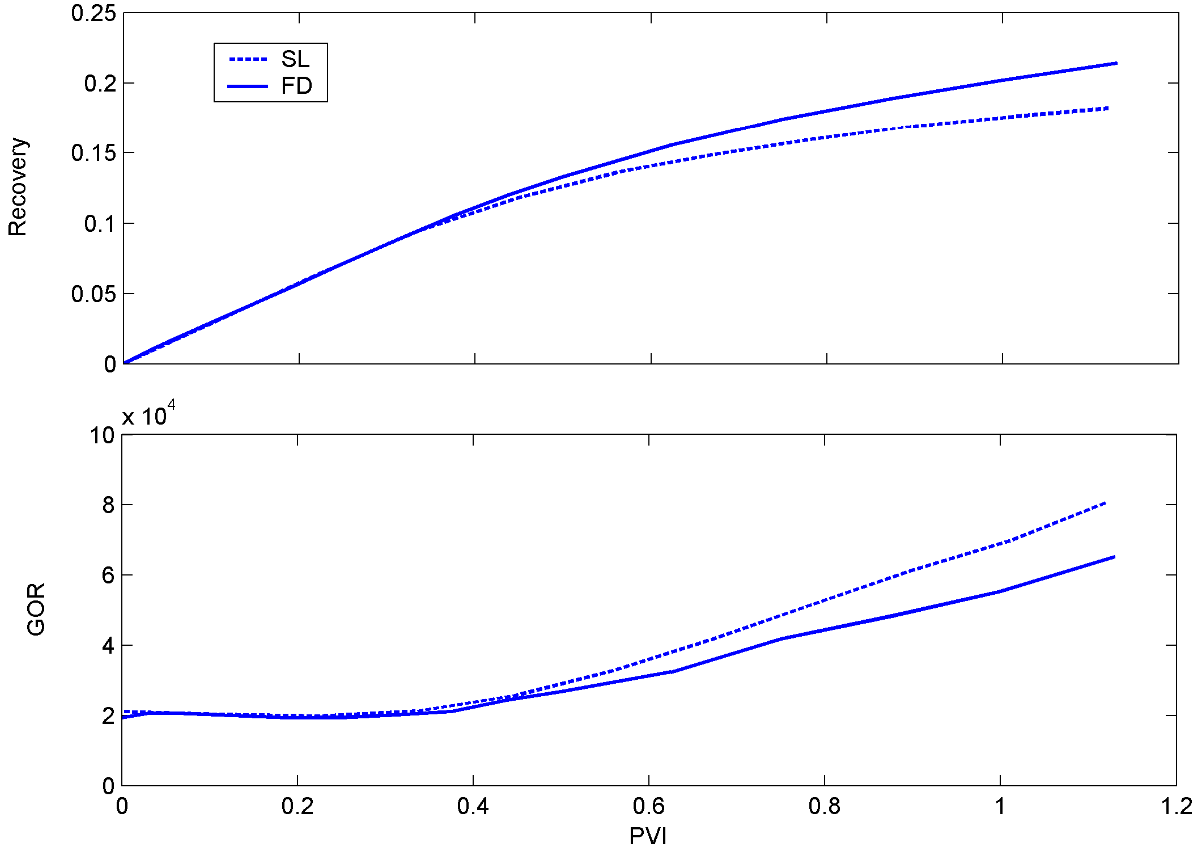

Fig. 16: Predictions of recovery and GOR from SL simulation and FD simulation of full-field model.